2002

ENERGY REGULATORS REGIONAL ASSOCIATION

Tariff/Pricing Committee

ISSUE PAPERS

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Introduction

Dear colleagues,

The Tariff/Pricing Committee was established in December 1998 as a part of the Energy Regulators Regional Association (established by NARUC in cooperation with US Agency for International Development). In December 2000, the Committee was officially approved as one of the two ERRA standing committees.

In the period from 1999 to 2002, the Committee has reviewed 16 topics. They were formulated taking into account wishes and priority objectives of the regulatory organizations from member countries. The process of reforms in these countries is at different phases, therefore, for some countries the issues considered under these topics are current problems requiring immediate solution, while for the other countries they represent pending problems that these countries will have to resolve in the framework of future reforms. Irrespective of that, all considered topics are of certain value and are directly related to main functions of the regulatory organizations.

Cooperation within the framework of the Committee, as well as exchange of experience and views of regulators on various topics that are of mutual interest, promotes better efficiency of their work, helps to improve professional skills and to cope with complex problems they are facing in the course of regulating their energy sectors.

I would like to express my gratitude to all Committee members for their creative contribution in the work of the Committee, I also want to thank US Agency for International Development, NARUC and ERRA for their comprehensive assistance, support and valuable suggestions.

I hope that our fruitful cooperation will continue in future and would be provide valuable assistance in the process of our countries' transition to free market economies.

Sincerely,

V.Movsesyan
Chairman, Energy Commission of the Republic of Armenia,
Chairman of the Tariff/Pricing Committee

Publication and dissemination of the documents pertaining to the 6th Annual Energy Regulatory Conference for Central/Eastern Europe and Eurasia was made possible through support provided by the Energy and Infrastructure Division of the Bureau of Europe and Eurasia under the terms of its Cooperative Agreement with the National Association of Regulatory Utility Commissioners, No. EEN-00-99-00001-00. The opinions expressed herein are those of the authors and do not necessarily reflect the views of the U.S. Agency for International Development.

Chapter 1

SYSTEM TARIFFS IN THE ELECTRICITY SECTOR

Prepared by Chairman V. Movsesyan
Chairman of the Energy Regulatory Commission of the Republic of Armenia

1. Objectives

In most of the ERRA member countries energy sectors are undergoing reforms. These reforms are carried out according to different models and at different rates, depending on:

- The economic situation of the country and social status of the population;
- Political situation and adopted concept of economic development of the country;
- Technical and financial situation of the energy sector;
- Other country specific factors (availability of local energy resources and generating capacities, volumes of production, geographic location, the size of the country, etc.).

In some countries the restructuring is done vertically –electricity system integrated by functional characteristics. As a result, separate electricity generation, transmission and distribution companies are established and they have horizontal commercial links. Other countries, for the time being, do not view such unbundling as being reasonable.

The carried out reforms and their phased future continuation are aimed at creation of real market relations in the energy sector, attraction of capital in the sector, ensuring energy security of the country. In the course of implementation of the named reforms, regulators responsible for development of the power engineering and ensuring energy security have to make a choice related to the energy sector structure, to specify what is the place and role in it of companies rendering system services, have to set criteria for performance measuring and mechanisms of payment.

2. Wholesale Market Model. Structures of System Services in the Electricity Wholesale Market Model

ERRA member countries can adopt (or already have) various models of the electricity wholesale market:

- Direct contracts between generators and buyers with the balancing market,
- Mandatory pool with full regulation of tariffs by the Regulator,
- Wholesale market with a Single buyer-seller and with regulated tariffs.

Irrespective of the adopted model of the electricity wholesale market, in order to ensure its normal operations and transparency, the following centralized system services should be provided:

- System operator,
- Accounting and mutual settlements between market participants,

- Signing agreements,
- Wholesale market cash flow administration.

Due to the above-mentioned circumstances, which are specific for each ERRA member country, models of the electricity wholesale market (functioning ones or those that have to be adopted) also differ, as well as structures that provide system services, as well as functions performed by them.

Below brief information on the existing wholesale market models or planned reforms in ERRA member countries is presented. The summary is based on the answers to the relevant questionnaire and it cannot give clear and comprehensive picture of the issue being considered. More detailed information on the market structures, on their advantages and disadvantages; on the problems that hamper implementation of efficient market mechanisms can be obtained from representatives of ERRA member countries. Nevertheless, preliminary familiarization with electricity wholesale market models of ERRA countries, as well as with planned reforms, is of certain interest from the point of view of their further more detailed discussion. Bearing that in mind, we provide short review of some of them.

The wholesale market model adopted in **Latvia** is somewhat different from the above-mentioned three models: direct contracts between «non-captive» customers (that consume more than 40 million kilowatt-hours) and generators; balance management by the System Operator; regulated tariffs for captive customers.

Energy sector of **Albania** is controlled by the Government, through a joint-stock company that is responsible for generation, transmission and distribution of electricity in the whole country. In order to identify direction of further reforms, carried out with the help of USAID, currently the Project "Development of the Electricity Wholesale Market" is being implemented. Implementation of the project will also allow clarification of the prospects of the regional electricity market in the Balkans.

According to the reforms carried out in the structure of the energy sector of **Armenia,** structures that provide services to all market participants should carry out the following major functions.

Power system operator:

- Is responsible for centralized operational-technological and economic dispatching of the energy system in accordance with the Wholesale Market Functioning Rules and signed contracts (including also electricity import-export contracts);
- Verifies the preparedness of operational and reserve capacities of electricity generators (that is necessary under the two-part payment system: for electricity and for capacity) and transfers necessary data to the Computing Center for subsequent payment;
- Transfers to the Computing Center dispatching data necessary for settlement;
- Exercises system planning and coordination of generation, import, export, and transit of power, in accordance with existing contracts and Wholesale Market Functioning Rules;
- Evaluates impact of the proposed electricity sale-purchase contracts (including contracts on export, import, exchange and transit of electricity) in terms of reliability and safety of power supply for domestic market consumers and for the functioning of the power system;
- Makes proposals to the market participants and Regulator concerning events aimed at power system development, maintenance of its reliability and safety;

- Calculates the size of facilities at each market participant for control and protection devices with system significance; monitors their operations in accordance with the license terms and Wholesale Market Functioning Rules;
- Develops system safety and reliability ratios and ensures compliance with them;
- Gathers and publishes data on functioning of the Wholesale Market.

The Computing Center has to have an integral system of data, which it needs for calculation of payments to each electricity generator, importer and exporter, distribution company and system service rendering company. In addition, it:

- Provides for operation and maintenance of the computerized system for accounting and collection of data needed for financial settlements;
- Computes power system balance and commercial losses in it, checks and verifies commercial data, restores missing metering data necessary for calculations, prepares bills for all market transactions;
- Computes actual and planned technological losses, compares them and makes proposals on compensation of losses incurred by the market participants due to deviation of actual technical losses from their budgeted values;
- On a periodic basis collects and processes data on electricity generation, transmission and distribution, which is necessary for conducting mutual settlements between market participants; and presents final bills subject to be paid (taking into consideration prepayments made and mutual settlements).

Wholesale Contractor

- Using authorities delegated to it by the market participants, and on their behalf, concludes contracts for export, import, transit and exchange of electricity (capacity), agreements on rendering system services to market participants, on the concurrent work with other power systems;
- Based on the specified by the buyer monthly demand for electricity (capacity), coordinates with generators (importers) amounts of necessary capacities, generation curves and records them in agreements.
- Monitors the compliance of transactions related to electricity and capacity in the domestic market between electricity generators and the distribution company with the Pool Agreement (agreement between electricity generators and the distribution company) and Market Functioning Rules;
- Makes forecasts for electricity export and interconnection flows depending on the time of the year.

At present, all the said functions related to rendering of system services are carried out by relevant divisions of the Single seller-buyer represented by the closed joint-stock company «Armenergo». In the course of further reforms, it is planned to convert from the wholesale market with a Single buyer-seller (who buys power from generators at individual two-part wholesale tariffs and sells it to the distribution company at a monomial wholesale tariff) to mandatory pool, where all sellers sell electricity, and all buyers purchase it from the pool. In such a case, all mentioned divisions would be able to become independent.
It is also planned to establish one more structure that would provide system services – Fund Administrator.

Fund Administrator

- Manages cash flows in a centralized manner, upon instructions of the Computing Center ensures performance of financial operations (related to wholesale deliveries of electricity and rendering of services) on allocation of cash flows among market participants;
- Ensures transparency of all financial transactions and their compliance with the Wholesale Market Functioning Rules.

Currently, in **Bulgaria** the Single buyer-seller model is working. For future it is planned to convert to direct contracts between electricity producers and buyers with balancing market.

In **Hungary** for captive customers, a wholesale market with Single buyer-seller will operate. All functions related to providing system services will be united in one structure (Hungarian Electricity System Operator) that will be an Independent System Operator with traditional clearing house functions.

System services will be purchased by the Independent System Operator from market participants and delivered to captive customers (population) and for basic purposes (stability, required voltage level, etc.). Costs of these services and costs related to maintenance of the Independent System Operator will be summarized and reflected in the Independent System Operator's fee controlled by the Regulator, this fee will be paid by each customer (but not as a separate element of the tariff for captive customers). Some customers will be entitled to buy additional system services (for example, additional reserve capacity) from other market participants.

Electricity wholesale market (EWM) existing in **Georgia** has a status of a legal entity. Organizational-legal form of EWM is a union of license holders and direct consumers in the electricity sector. Functions of the Power System Operator (National Dispatching Center) are carried out by an independent legal entity – holder of a license on dispatching. Functions of the Fund Administrator and Computing Center are carried out by a structural division of EWM, which has its General Manager and its Board of Directors that consists of license holders, representatives of the Ministry of Fuel and Energy, Ministry of Economy and Ministry of Finance. EWM is accountable to the Regulator.

According to the Law On Energy of **Lithuania**, customers are entitled to buy electricity from energy supply enterprises or from independent suppliers licensed to supply electricity. Suppliers can purchase electricity at auctions or directly from generators, and balancing electricity can also be purchased from the Market Operator.

Suppliers should be responsible for billing in accordance with supplied electricity and rules for electricity consumption, approved by the Government or any other authorized body.
In accordance with the Law mentioned above, the market structure with direct contracts between producers and electricity buyers with balancing market should be adopted. In addition to the Power System Operator, Computing Center and Fund Administrator there also should be a Market Operator, performing functions of the auction organizer. The legal basis for converting to this structure is almost in place; just certain technical obstacles need to be eliminated.

There are no such system services as Single buyer-seller, or Fund Administrator in **Moldova**. Electricity market operates on the basis of bilateral contracts between electricity producing and distribution enterprises or importers. The system operator (Dispatching Center) is a division of the state owned transmission company. In the future it is planned to establish separate enterprises for transmission of electricity and an Independent System Operator for the National Energy System.

Currently, 67% of the wholesale market of **Romania** is regulated and 33% is competitive. The structures providing system services are Power system operator and Market Administrator. The latter collects all bids and calculates the marginal price for the energy system. It calculates payments between subjects, collects and allocates the money. The Dispatching

Center is a part of the National Transmission Company. This is a state owned company and it is a Single buyer-seller for ancillary services.

Currently, there is no final model of the electricity market in **Slovakia**, however, it has been stated that the function of the Power system operator will be carried out by the Transmission System Operator (including National Dispatching Center).

Transmission System Operator with its computing center and fund for ancillary services is the Power system operator in the **Czech Republic**. The system services are provided by the Transmission System Operator through the Market of ancillary services.

There is one large generator (Estonian Energy) in **Estonia;** it owns transmission and distribution networks and it supplies electricity. In future Baltic Energy Pool will be adopted. In the opinion of some countries, the structures that provide system services should be separate, while others believe that these structures should be partially merged. For example, currently in **Lithuania** the Power system operator (National Dispatching Center), Computing Center and Market Operator are parts of one enterprise. In the course of further reforms it is planned to restructure the Market Operator and make it a separate Auction Company) or Power Exchange. It is assumed that in the initial stage, the Market Operator can perform functions of the Fund Administrator.

In **Poland**, the Power system operator, Fund Administrator and Computing Center are united and form part of a distribution company.

In the opinion of the **Hungarian** Regulator, financial operations should be carried out by the Independent System Operator.

In the pattern of the wholesale market of **Georgia** functions of the Fund Administrator are performed by the EWM organization department, through a bank transfer account.

The wholesale market model of **Romania** does not envision any Fund Administrator.

In our opinion, one important circumstance has to be mentioned, the one that should be taken into account when choosing the structure of enterprises that render system services. As a rule, in all power systems, the power system operator (dispatching service) generally has responsibility for the safety and reliability of the power system. As for a single buyer-seller, then its commercial interests in some cases may not correspond to the interests of the system operator with regard to ensuring system safety and reliability. From this standpoint, having the buyer-seller and the power system operator be part of the same structure could have negative consequences on the performance of the system operator, which could ultimately decrease system safety and reliability. For this reason, systems with a single buyer-seller should strive to have the system operator be independent from the buyer-seller structure.

There is an opinion, that functions of the fund administrator can be delegated to one of the financial institutions (as it has been done, for example, in **Czech Republic** and is intended to be done in **Armenia**, to a highly respected bank), which will perform financial operations though the transit account system. The feasibility of this scheme should be evaluated, and it should be compared with alternative options of managing financial flows in the energy sector.
It is also necessary to state whether there are other system services, on top of the named ones, for which it might be reasonable to create additional separate structures, and also to explore advisability of consolidation (by merging two or more structures into one) of the said structures.

Special attention should be paid to forming, on the voluntary basis, a Union of electricity wholesale market participants, and to specification of its relations with structures that render system services.

3. Status of companies that render system services

There are different opinions concerning the status of companies that provide system services. Considering the strategic significance of the power sector, more than half of the ERRA member countries support the opinion that the principals of companies providing system services should be the government. Some also believed that market participants or private companies could also be principals along with the government. In other cases involvement of the government in this issue is completely excluded, and only market participants are entitled to be principals in these companies. Apparently, supporters of the latter approach are worried that in case these companies have a governmental status, the Government might influence them in order to resolve other problems urgent for the Government at the expense of the energy sector, or might follow protective policy for the benefit of state-owned energy companies.

4. Designing tariffs for system services

In order to set tariffs for system services, it is necessary to determine costs associated with maintenance of these companies, in particular, the number of personnel, and its payroll. At the same time, the level of participation of each market participant in financing operations of structures that provide system services should be identifies, as well as the role of the Regulator in approving these costs (as in the long run they affect electricity tariffs).

Setting tariffs for system services require clarification also of other rather important issues. We should mention some of them.

What should be payment for system services: fixed, paid monthly, or should it depend on certain parameters describing the volume of operations of companies providing system services (i.e. correspond to payments for a conventional unit of provided services)? In the latter case, is it reasonable to differentiate these parameters depending on the type or nature of the provided service? For example:

- For computing center (company that calculates payments for each generator, importer and exporter of electricity, each distribution company and companies that provide system services) to set payments that would depend on the number of points of commercial metering of electricity;
- For the wholesale contractor (who concludes contracts for market participants and companies providing system services, and who also monitors the compliance of transactions related to electricity and capacity in the domestic market between electricity generators and the distribution company with the Pool Agreement (agreement between electricity generators and the distribution company) and Market Functioning Rules) – depending on the number of signed contracts and their volume;
- For the power system operator (who is responsible for centralized operational-technological and economic dispatching of the power system) – depending on the amount of generated electricity and/or peak capacity of the power system;
- For high-voltage lines – depending on the amount of electricity being transmitted and/or capacity.

A question, which of the licensed power market participants should pay to companies providing system services also needs to be answered?

In the regulated market conditions the cost of system services, in most cases, is paid only to distribution companies and it is reflected in their tariffs (margin). This is a quite simple method of payment for system services and the most rational one from the point of view of cash flows. At the same time, the shortcoming of this method has to be mentioned, though companies providing system services receive full payment for all rendered services, it is done not by every market participant in accordance with the amount of services received by it. In such situation, no commercial relations are established between market participants who do not pay for system services directly and companies rendering such services. To a certain extent it reduces responsibility of system service providers towards beneficiaries of these services and deprives the latter of financial instruments that might have been used in case of poor quality services.

In the competitive market such method of payment for system services is eliminated. Each market participant who gets system services pays its share according the strictly set tariffs.

The next question ensuing from the above stated one: if in the regulated wholesale market distribution companies fully pay for all provided system services, whom should exporters buying electricity in the wholesale market pay for received system services? If they have to pay to companies providing system services, then the latter generate additional income. And if they have to pay to distribution companies, then they have to return these funds to end users who pay for system services through tariffs.

An issue of setting criteria for evaluating the operating efficiency of companies providing system services, and depending on their compliance with these criteria, application of motivating tariff system for them needs thorough examination

In **Poland** such tariff system is already applied because of introduction of the incentive regulation.

The **Hungarian** Regulator believes that though the market will define the cost of system services, it is desirable to restrict its (cost) unjustified growth.

ERRA member countries have no common point of view in terms of the possibilities of system service rendering structures to generate profits.

More than half of questioned ERRA member countries consider it unreasonable to apply a motivating tariff system for enterprises that render system services, which point of view is not shared by other countries. The advisability of application of this or that approach needs to be well grounded.

Chapter 2

Two-part tariffs for electric power consumers

Prepared by Commissioner Florin Gugu, Director, Prices & Tariffs and Economical Analysis Department
Romanian Electricity and Head Regulatory Authority

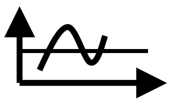
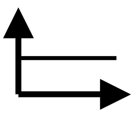
1. Purpose Of The Paper

The present paper should represent a tool for highlighting issues to be considered by the regulators related to pricing methodologies, the way that two-part tariffs are designed, indicating areas where further efforts are needed and to suggest possible follow-on activities for the CEE/Eurasia Tariff Committee. Section A of the present report represents a partially update of the *Issue paper No.2/2001: Differentiated tariffs in the wholesale and retail market*

At the same time the paper serves other more general purposes such as:

- To review the extent to which the energy sector has been restructured and the market opened;
- To identify activity areas where the prices are regulated and areas where competition was implemented;
- To identify approaches used in the CEE/Eurasia region for addressing zone and time differentiation; and,
- To share between CEE/Eurasia Tariff Committee members the experience in addressing the above-mentioned issues, learning from others' mistakes in the hope of finding the best solutions.

Abbreviations and Legend:

N.A.	Not available
REC	Regional Electricity Company
OTH	Other
	Time differentiation based on load curve shape
	No time differentiation
	Time differentiation based on costs

2. Answers To The Questionnaire

A. General Presentation Of End-User Tariffs

According to the European Directives energy sector reform should include also a program for market opening. Many experts say that the degree of market opening reflects the status of the reform in energy sector.

As shown in ***Table 1*** some countries like Estonia, Hungary, Latvia, Lithuania, Poland, Romania and Slovakia have opened the market within the range of 13.76-51 %.

The questionnaire has revealed that most preferred criteria for declaring the eligible consumers was the annual consumption. The threshold for the annual consumption varies between 6.5-100 GWh/year. Other used criteria are the subscribed demand (Estonia) and financial soundness (Romania).

This section of the present report represents a partially update of the ***Issue paper No.2/2001: Differentiated tariffs in the wholesale and retail market.***

End-user tariffs for captive consumers are regulated in order to cover the aggregated costs for generation, transmission, distribution and supply. In most of the countries tariffs are uniform over the country (Albania, Bulgaria, Hungary, Latvia, Lithuania, Kyrgyz, Romania, Slovakia) or over a region served by a REC (Czech, Estonia, Georgia, Moldova, Poland and partially for industry, in Ukraine). From 01.04.2002, tariffs will be uniform over a region served by a REC in Lithuania. In Russian Federation, there are end-user tariffs designed and regulated for each geographical zone. In all these countries voltage and demand levels and load curve factors differentiate end-user tariffs.

Table 2 contains a more detailed presentation of end-user tariffs.

Table 1. Market opening

Country	Captive end-users	Eligible end-users	Eligibility criteria		
	%	%	Annual consumption [GWh/year]	Demand [MW]	Other
Albania	100	-	-	-	-
Armenia	n.a.	n.a.	n.a.	n.a.	n.a.
Bulgaria	100	-	-	-	-
Czech	-	-	40	-	-
Estonia	80	20	40	8	-
Georgia	-	-	-	-	-
Hungary	67	33 (01.01.2003)	6.5	-	-
Kazakhstan	n.a.	n.a.	n.a.	n.a.	n.a.
Kyrgyz	100	-	-	-	-
Latvia	86.24	13.76	40	-	-
Lithuania	79	21	20	-	-
Moldova	100	-	-	-	-
Poland	49	51	10	-	-
Romania	67	33	40	-	Economic, financial soundness
Russia	n.a.	n.a.	n.a.	n.a.	n.a.
Slovakia	70	30	100	-	
Ukraine	100	-	-	-	-

Table 2 End-user tariffs

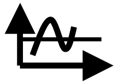
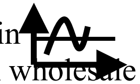
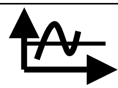
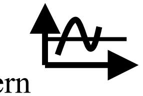
Country	**Tariffs system is organized by:**	**The tariffs system contains:**
Albania	-voltage levels -customer type	-simple monomial tariff
Armenia	-voltage levels	-simple-part tariff differentiated on two time zones
Bulgaria	-voltage levels	-simple monomial tariff
Czech	-voltage levels -demand levels and load factors	- simple monomial tariff - monomial tariff differentiated on time zones - monomial tariff with a fixed charge - simple binomial tariff - binomial tariff differentiated on time zones - simple trinomial tariff - trinomial tariff differentiated on time zones
Estonia	-voltage levels -customer type	- simple monomial tariff - monomial tariff differentiated on 2 time zones - monomial tariff with a fixed charge - simple binomial tariff
Georgia	-voltage levels -customer type	- simple monomial tariff
Hungary	-voltage levels -demand levels and load factors	- simple monomial tariff (for residential consumers) - monomial tariff differentiated on 2 time zones - monomial tariff with a fixed charge - simple binomial tariff (for low voltage only) - binomial tariff differentiated on 2 time zones
Kazakhstan	n.a.	n.a.

Kyrgyz	- customer type	- simple binomial tariff
Latvia	- voltage levels	- simple monomial tariff - monomial tariff differentiated on time zones - binomial tariff differentiated on time zones
Lithuania	-voltage levels -demand levels and load factors	- simple monomial tariff - monomial tariff differentiated on 2-4 time zones
Moldova	n.a	- monomial tariff differentiated on time zones
Poland	- voltage levels - demand levels and load factors - consumer type - other	- monomial tariff with a fixed charge - binomial tariff differentiated on 3 time zones
Romania	-voltage levels -demand levels and load factors	- simple monomial tariff - monomial tariff differentiated on 2 time zones - monomial tariff with a fixed charge - simple binomial tariff - binomial tariff differentiated on 2-3 time zones
Russia	n.a.	n.a.
Slovakia	- voltage levels - demand levels and load factors	- simple monomial tariff - monomial tariff with a fixed charge - simple binomial tariff
Ukraine	- voltage levels	- simple monomial tariff - monomial tariff differentiated on time zones

Table 3 End-user tariffs differentiation

Country	Tariffs uniformity:	Tariffs differentiation type:
Albania	-uniform all over the country	-seasonal periods **OTH**
Armenia	-uniform all over the country	-day-night differentiation -the definition of time zones is based on the system's load curve
Bulgaria	-uniform all over the country	- day-night differentiation for residential customers - hourly zones during the day for industry - system's load curve pattern
Czech	-uniform over the region served by a REC	hourly zones during the day day-night weekend week days definition of time zones based on: system's load curve pattern + pricing policy
Estonia	-uniform over the region served by a REC	-day-night differentiation -the definition of time zones is based on the system's load curve pattern
Georgia	-uniform over the region served by a REC	-
Hungary	-uniform all over the country	-differentiation type:

		-hourly zones during the day (peak, off-peak) -weekend (off-peak) -the definition of time zones is based on the system's load curve pattern
Kazakhstan	n.a.	
Kyrgyz	-uniform all over the country	-day-night differentiation -the definition of time zones is based on the system's load curve pattern
Latvia	-uniform all over the country	-differentiation type: day-night weekend -the definition of time zones is based on the system's load curve pattern
Lithuania	-uniform all over the country	-differentiation type: day-night day-night weekend -the definition of time zones is based on the system's load curve pattern
Moldova	-uniform over the region served by a REC	-tariffs are differentiated on hourly zones during the day **OTH** -the definition of time zones is based on pricing policy
Poland	-uniform over the region served by a REC	Differentiation type: hourly zones during the day day-night weekend week days seasonal period - seasonal periods -the definition of time zones is based on pricing policy and system's load

		curve pattern
Romania	-uniform all over the country	Differentiation type: hourly zones during the day day-night weekend seasonal period - seasonal periods -the definition of time zones is based on system's load curve pattern 
Russia	-in the wholesale market, within zones (Central, Northwest, South, Urals, Siberia, Far East). -in the consumer (retail) market, within individual constituent members of the federation regulated by regional energy commissions.	-differentiation of time zones. there are six zones in the Russian Federation, each of which has its own wholesale market tariff -the retail market uses single-rate, dual-rate, and zonal tariffs. -time zones are based on system load curve and pricing policy 
Slovakia	-uniform all over the country	-differentiation type: hourly zones during the day -time zones are based on system load curve pattern 
Ukraine	-uniform over the region served by a REC	-differentiation type: hourly zones during the day and day-nigh -time zones are based on system load curve pattern 

B. METHODOLOGIES FOR DESIGNING THE TWO-PART TARIFFS

The questionnaire has shown that most of the countries use fixed/variable components for designing the two-part tariffs. Unfortunately the models used in each country are not known, but in the case of Romania the two components are the sum of the upstream components (each activity has it's own tariffs).

Most of the models relate the fixed cost component to the subscribed demand and just a few relate it to measured demand or consumption point.

Table 4

Country	Basic principle			Fixed cost component related to		
	variable/fixed component	commodity/services separation	other	subscribed demand	Measured demand	consumption point
Albania			√			√
Bulgaria						
Czech Republic	√					
Estonia	√			√		
Georgia	√					
Hungary	√			√		
Kyrgyz Republic	√			√		
Latvia	√	√		√		
Lithuania						
Moldova						
Poland	√	√		√		√
Romania	√	√		√	√	
Slovakia	√				√	
Ukraine	√	√		√		

As shown in *Table 5* most of the services tariffs are related to energy and consumption point and only two to measured demand and two to contracted demand.

Network losses are in most of the cases are cost-recovered through an energy charge component included in distribution tariffs or end-user tariffs. Only 4 models use the loss coefficients related to supplied energy.

Table 5

Country	Services tariffs are related to			Network losses are recovered by			
	Subscribed demand	Measured demand	Consumption point	Loss coefficients related to the supplied energy	Loss coefficients associated to injection/extraction points	Energy charge	
						Included in distribution tariff	Included in end-user tariff
Albania							√
Bulgaria							√
Czech Republic		√		√			
Estonia		√				√	
Georgia						√	
Hungary			√			√	√
Kyrgyz							√
Latvia			√				√
Lithuania				√		√	√
Moldova							√
Poland	√			√			
Romania			√			√	√
Slovakia							√
Ukraine	√			√		√	√

Although demand charge is differentiated in some of models (Estonia, Hungary, Kyrgyz, Latvia, Poland, Romania, Slovakia and Ukraine) only a few models use load factor differentiation and time zone differentiation. This is shown in ***Table 6***.

Table 6. Demand charge

Country	Demand charge is differentiated on		
	Time zones	**Load factors**	**Other**
Albania	-	-	-
Armenia	n.a.	n.a.	n.a.
Bulgaria	-	-	-
Czech	-	-	-
Estonia	2 - load curve pattern	-	-
Georgia	-	-	-
Hungary	2	-	-
Kazakhstan	n.a.	n.a.	n.a.
Kyrgyz	-	-	>150 kW
Latvia	-	-	Yes
Lithuania	-	-	-
Moldova	-	-	-
Poland	-	-	Yes
Romania	2	3	4 voltage levels
Russia	n.a.	n.a.	n.a.
Slovakia	1	-	yes
Ukraine	yes	yes	Yes, by voltage level

In most of the countries there is no subscription fee. In the countries that have a subscription fee it is most of the cases not differentiated. Only in Latvia, Romania and Ukraine the subscription fee is related to demand. Table 7 presents the situation in all the countries that were analyzed.

Table 7. Subscription fee

Country	Subscription fee		
	Uniform	**Related to subscribed demand**	**Other criteria**
Albania	-	-	-
Armenia	n.a.	n.a.	n.a.
Bulgaria	-	-	-
Czech	-	-	-
Estonia	yes	-	-
Georgia	-	-	-
Hungary	-	-	-
Kazakhstan	n.a.	n.a.	n.a.
Kyrgyz	-	-	Yes
Latvia	-	yes	-
Lithuania	-	-	-
Moldova	-	-	-
Poland	yes	-	-
Romania	For household	Yes (indirectly)	-
Russia	n.a.	n.a.	n.a.
Slovakia	-	-	-
Ukraine	-	yes	-

3. Conclusions And Recommendations For Further Work

Major conclusions of this paper include:

Day by day new countries open the market or increase the degree of the opening. This results in restricting the zones with cross-subsidies among consumer classes. The difficulty is that the energy sector has historically been used as a means for implementing social policy. This may make it difficult in the near-term to eliminate the role of the regulated energy sector, but nonetheless, the objective should be to reduce this involvement over time. The more market opening will have, the less involvement might occur.

Opening the market and introducing competition in the areas where the activity doesn't have a natural monopoly character will result in a generalized need to introduce time-differentiated tariffs at the end-users. This will result in a much better fit between the cost curve and the revenue curve, and will help sending a more accurate economic signal to the consumer.

The tariff is an economic signal sent to the consumer. The consumer is expected to react accordingly. One easy way to create a more complex signal is to time differentiate the tariffs. The supplier will obtain benefits due to consumer's response and also due to the fact that the revenues for the supplied electricity in a certain period of time are quite close to the cost induced into the system. Time-differentiation is severely restricted due to the lack of metering equipment and data tele-transmission. Anyway, implementation process was accelerated due to the new generation of electronic meters that could be installed gradually, beginning with the largest consumers.

4) One other easy way to create a more complex signal for the consumer is to use two-part tariffs. Practice has shown that this is the best incentive to determine the end-user to improve his load factor, and produce the “peak clipping”.

5) There are various models used to design the two-part tariffs. Most of the models use fixed/variable component breakdown, and relate the fixed component to the subscribed demand. Most of the models don’t differentiate the demand charge and in most of the countries there is no subscription fee.

Activities in the electricity sector are strongly interdependent one to another. Various economic signals (represented by tariffs) for each activity are aggregated in the tariff for end-users. Therefore the two-part tariffs for end-users might reflect the two-part tariffs for the upstream activities or the effort to charge the consumers exactly the costs that they induce in the system.

Taking into consideration the purpose of the present paper some recommendations are highlighted in order to indicate areas where further work of the Tariff Committee may be justified.

To the extent that the regulated energy sector is in fact burdened with the responsibilities of the Government, it would be useful to examine how regulatory institutions can monitor and evaluate the ways of accelerating the opening of the market and introducing competition in the areas where the activity doesn’t have a natural monopoly character. In this regard, Committee members can review and discuss the progress made by the member countries, the various models used, their advantages and disadvantages.

Committee members can discuss in detail how two-part tariffs are designed, what infrastructure was needed and with what costs, which are the best-suited options for the specific conditions of a country.

Committee members can present models for two-part tariffs, the efficiency of the models under specific conditions, share from the accumulated experience.

Chapter

3

PRICING POLICY FOR SMALL INDEPENDENT GENERATORS

Prepared by Commissioner Svetla Todorova
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Introduction

The Tariff/Pricing Committee proposed to include Issue Paper related to the regulatory problems on micro and small hydroelectric, combined heat/power plants and encouraging use of alternative energy resources in 2002 Workplan. The main purpose of the Paper was to review the extent to which the micro and small hydroelectric are applied in different countries, to identify approaches used in the CEE/Eurasia region for introducing incentives, to share between Committee members the experience in addressing the above mentioned issues and learning more about prospective of future development of small sources of energy.

For the beginning there was prepared Questionnaire on Small independent power producers (SIPP), Combined heat and power plants (CHPP), Renewable energy resources (RER) for an indication of problems and general situations in related energy sectors in different countries.

During the April Committee meeting it was decided to extend the topic with more details concerning Distributed Generation (DG) - small electrical power generation sources generally less than 20 MW. The reason was that DG technologies were increasingly being adopted because of increased competition in the electricity sector, and the ability of DG to provide reliability, environmental, and other economic benefits.

Second questionnaire have been prepared focusing on definition of DG as used in individual ERRA member countries, legislative and regulatory processes and requirements for the sitting of a new generator or operating an existing one, opportunities to sell the generated electricity, incentives for promoting DG, regulated tariffs for generated electricity, regulated tariffs for balancing electricity.

This paper includes summarized answers of above-mentioned two questionnaires from some CEE/Eurasia countries.

Relevant documents, used for elaboration of this paper, were White Paper on Energy Policy, experience in USA from publications of The Association of Energy Engineers, Distributed Generation Strategic Plan of California Energy Commission.

European Union energy policy declares general aims of the Community's economic policy based on market integration, deregulation, limiting public intervention to what is strictly necessary in order to safeguard the public interest and welfare, sustainable development, consumer protection and economic and social cohesion. Beyond those general aims energy policy must embody competitiveness, security of supplies and protection of the environment. It means that the Commission will continue to work on fiscal instruments by helping the Member States to restructure their own taxation policies, intensifying efforts to meet environmental challenges by promoting in the generation of electricity cleaner and more efficient technologies, particularly renewable energies. The European Parliament, while advocating the liberalization of the energy markets also emphasized the need to guarantee security of supply, public services missions and environmental protection. The general framework for an energy policy is characterized by four key concepts: globalization of markets, increasing environmental concerns, technology developments, and institutional responsibilities. Improving access to indigenous energy resources, including renewable energies, by helping to improve the fuel mix and by achieving higher energy efficiency and further energy savings is featured by increasing environmental concerns and technology development.

Emerging energy trends indicate that concerns on climate change, the effects of technology and the liberalization of markets and the fact that some renewable are on the threshold of economic viability will be the major determine factors for policy implications. On the other hand energy use in forecast shows that electricity generation by gas-fired plants could reach almost half of total thermal capacity, most of it combined-cycle plants. The prevailing trend in Europe shows that heat from decentralized cogeneration plants and renewables, in particular biomass, biofuels and wind, could make significant gains, squeezing the share of oil. Solid fuels will remain significant in the thermal electricity market. Trends in CO_2 emissions would take a strong switch to non-fossil fuel electricity, essentially nuclear and renewable generation, to reduce substantially CO_2 emissions from the electricity sector.

In the guidelines for energy policy implementation Commission will propose to the European Standardization Bodies to promote of energy efficiency, renewable energies and energy transportation by means of special standards. The Commission has guidelines on state aid for environmental purposes, which also cover state aids for energy efficiency and renewable energy. These guidelines include the possibility of more favorable thresholds for renewables. At the same time Commission concludes that all forms of energy should have a fair chance to compete on the market. Electricity prices should not be used to support specific forms of energy. However energy like renewables may need to be supported initially through specific programs or subsidies in order for them to find the place on the market. Such support should be given in a manner that is least harmful to competition. Commission will analyze whether it is necessary to extend the excise duties on mineral oils to cover competing energy products. It should be noted that this subject needs very careful analysis as the various forms of energy do not follow the same pricing philosophies (cost plus versus market value). Commission emphasizes importance of transparency of prices and taxation for users and producers of energy.

Commission points out importance of monitoring the internal energy market. This monitoring must envisage the freedom of establishment for independent electricity producers and ensure the business environment offers fair competition for such electricity producers. Recommendations on creating a favorable climate for investment point out that environmental objectives can contribute to energy objectives such as energy efficiency, renewable energies and cogeneration.

Commission highlights that for sustainable development assessing specific environmental actions with cost-benefit analysis is an essential instrument to implement balanced decisions. This cost-benefit analysis should integrate not only the impact on companies but also the impact on energy policy such as on the balance of fuels and energy supplies. This concept provides measures for the balance of taxation from labor to scarce natural resources. For the energy sector this could result in an increase in relative prices compensated by a parallel change in indirect taxes on labor. States could consider whether some of revenue could be rechannelled in the form of incentives for investments in cleaner technologies, energy efficiency improvements, etc. There is specified that a Community's strategy is to promote cogeneration and district heating with assistance in dismantling barriers to the development of that technology. Concerning renewables Community constitutes that in the long-term its will be the main sustainable energy source. So the promotion of renewables in the present situation of the energy market needs supportive market regulation permitting these investments to compete with others. There is scope for action to promote the penetration of renewables: solar, wind, biomass, biofuels, geothermal.

Overview of some relevant publications from "Strategic Planning for energy and the Environment" 1997 - 2002 period.

L.S.Hyman. Renewable Energy Resources Advice,SPEE, 2000, vol. 19, No. 3, p.p. 42-48.

You've probably heard all this garbage about how that all-knowing market solves all problems, but the market won't work here, because pricing doesn't take into account all the costs to society of using the wrong energy sources….that argument is correct and government could correct the problem through taxation or a trading regime…the renewables industries are betting on Kyoto.

Dr. R.L.Bradley. Renewable Energy: not cheap, not green? SPEE, 1998, vol. 17, No. 3, p.p. 15-21.

A multi-billion-dollar government crusade to promote renewable energy for electricity generation, now in its third decade, has resulted in major economic costs and unintended environmental consequences. Even improved new generation renewable capacity is, on average, twice as expensive as new capacity from the most economical fossil-fuel alternative and triple the cost of surplus electricity. Solar power for bulk generation is substantially more uneconomic than the average; biomass, hydroelectric power, and geothermal projects are less uneconomic. …eco-energy planning is the belief that government intervention in the energy economy is necessary to maximize environmental protection and the nation's economic vitality. …The new (post-1980) mission of many state public utility commissions has been to intervene in the market with incentives for renewable energy generation and conservation… in supply side:

- Tax code preferences for renewable energy generation;
- Ratepayer cross-subsidies for renewable energy development;
- Mandatory utility purchases of power generated by renewable energy sources at the utilities' "avoided cost";
- Imputed environmental costs ("full environmental costing") to penalize fossil-fuel-generation planning choices;
- Fuel diversity premiums to penalize reliance on natural gas for power generation;
- Government payments for renewable energy research, development and commercialization;
- Early entry into open-access programs for renewable energy generation.

In demand side:

- Taxpayer subsidies for energy-efficiency programs;
- Ratepayer subsidies for energy efficiency, called demand-side management;
- Minimum energy-efficiency building and appliance standards.

Eco-energy planning is presently confronting three major obstacles:

- Renewable energy options, prominently including hydroelectricity and now wind power, have environmental drawbacks that have proven intractable to date;
- Renewable energy subsidies and mandatory energy conservation are proving to be incompatible with a competitive restructuring of the electricity industry because of unfavorable economics and surplus existing capacity;
- Economic and environmental advances in the fossil-fuels industry, particularly in the use of natural gas in electricity generation have reduced the environmental costs.

<u>R.A.Kennedy. Green Power, Energy Conservation and Cost Savings, SPEE, 1999, vol. 19. No. 1, p.p. 6-22.</u>

"Green power" implies minimal environmental impact. While hydroelectricity is a form of renewable energy, already existing hydro may be excluded from green power programs because buying this power will not help expand the green power market. …The deregulation or restructuring of the electric market provides numerous opportunities…to produce win-win results.

<u>California Energy Commission, Distributed Generation, Strategic plan, 2002</u>

"The distributed generation industry is at a crossroads: it can emerge from its infancy to become a major contributor to California's electric system or it can remain on the sidelines, serving niche markets for remote, emergency, or other special power needs. When the state teetered on the verge of rolling blackouts last year, consumers became more aware of the need for peak-load reduction, increased power quality and grid reliability, which are key features offered by distributed generators. At present, more than 2,000 megawatts of distributed generation facilities have been installed in California, with an expected 300-400 megawatts in small-scale projects to be added on an annual basis in the near term."

Distributed generation has been defined in many ways, creating some confusion in terms of regulatory rule applicability. It is most commonly defined as the generation of electricity near the intended place of use. Some parties define it with size limitations, other exclude back up generation, and yet others make no distinction between generation connected to the transmission system or the distribution system. As a basic definition assumes the following: *DG is electric generation connected to the distribution level of the transmission and distribution grid usually located at or near the intended place of use.*

<u>S.F.Rivera.Distributed generation challenges, SPEE, 2001, vol. 20, No. 3, p.p.63-80.</u>

Distributed generation (DG) technologies are small electrical power generation sources that are generally less then 20MW. DG technologies that are currently available include wind power, small- and micro-turbines, fuel cells, photovoltaic, reciprocating internal combustion engines. The equipment may serve emergency standby needs, peak power demands, intermittent needs and/or base load operations. Depending on the technology, the equipment may be used to generate electricity or in combined heat and power application. DG is being positioned in the marketplace as an option for the traditional central power plant energy suppliers, as well as a source of reliable and cost-effective energy supply.

Why Distributed generators?

Distributed energy resources (DER) are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user. DER can be beneficial to both electricity consumers and if the integration is properly engineered, the energy utility.

It is generally accepted that centralized electric power plants will remain the major source of electric power supply for the near future. DER, however, can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also in some cases benefit the electric utility by avoiding or reducing the cost of transmission and distribution system upgrades.

For the consumer the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are all reasons for interest in DER. The use of renewable distributed energy generation and "green power" such as wind, photovoltaic, geothermal or hydroelectric power, and can also provide a significant environmental benefit.

Some of the primary applications for DER include:

- Premium power - reduced frequency variations, voltage transients, surges, dips or other disruptions
- Standby power - used in the event of an outage, as a back-up to the electric grid
- Peak shaving - the use of DER during times when electric use and demand charges are high
- Low-cost energy - the use of DER as base load or primary power that is less expensive to produce locally than it is to purchase from the electric utility
- Combined heat and power (cogeneration) - increases the efficiency of on-site power generation by using the waste heat for existing thermal process

Users of DER have different power needs. Hospitals need high reliability (back-up power) and power quality (premium power) due to the sensitivity of equipment. Industrial plants typically have high-energy bills, long production hours, and thermal processes, and would therefore seek DER applications that include low-cost energy and combined heat and power. Computer data centers require steady, high-quality, uninterrupted power (premium power). DER technologies are either available now or are being developed to meet these needs.

How much costs the electricity from DG?

The price of the electricity is one of the main questions deciding to introduce ore to encourage new technologies. In this section there are some figures and a simple example how to answer this question.

Capital and Installation Costs

Capital and installation costs include the cost to purchase and install a DER technology at a specified location. Capital costs refer to the total equipment cost of a power generation system (i.e., fuel cell system, combustion turbine, etc.) to the end user. The table below shows capital cost ranges for a variety of DER technologies.

Capital Cost of Selected DER Equipment *($/kW)*	
Micro turbine	700-1100
Combustion Turbine	300-1000
IC Engine	300-800
Stirling Engine	2,000-50,000
Fuel Cell	3,500-10,000
Photovoltaic	4,500-6,000
Wind Turbine	800-3,500

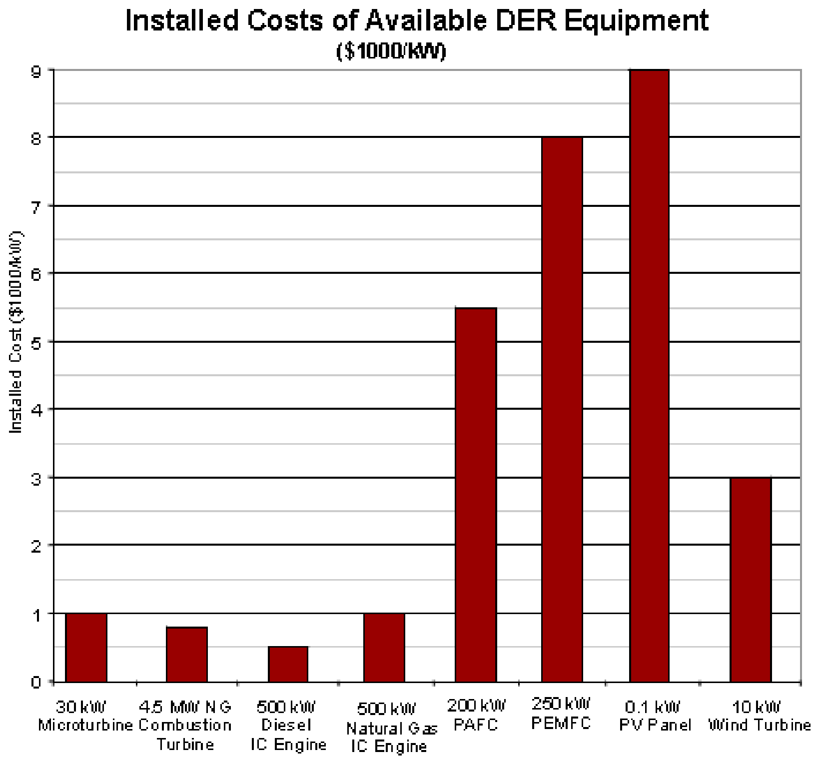
The capital costs for DER technologies can vary significantly even within the same technology, depending on size, power output, performance, fuel type, etc.

- Micro turbine costs represent early commercial production costs and will likely decrease as production levels increase.
- Combustion turbines are a mature technology with high production levels. Larger turbines generally cost less per kW than smaller turbines.
- Reciprocating engines are a mature technology with high production volume, therefore costs are relatively low. Larger reciprocating engines cost more per kW than smaller engines because they are manufactured in smaller quantities.
- Stirling engine manufacturers target lower costs (~$2000) if higher production volumes are achieved. The high costs reported in the table refer to low production and prototype engines, primarily for space programs.
- Fuel cells are in varying stages of development and production, as represented by the large range in capital costs.
- Photovoltaic systems are a relatively mature technology. The photovoltaic systems vary in cost by system type and system size.
- Wind turbine costs also vary with the size of the project. Lower costs (i.e. $800/kW) are associated with large utility scale wind farms. Residential size wind turbines can range in price from $2,500-$3,500/kW.

Installation costs will also vary widely within a given technology, especially for less mature technologies. Installation costs are often approximately 30% of the capital cost, but can reach as high as 100% for highly customized applications.

The total installed cost of the DER technology is the sum of the capital cost and installation costs. The total installed cost may include the power generation module, the power-conditioning unit, balance of plant equipment, installation, general facilities and engineering fees, project and process contingencies, and owner costs.

The following chart illustrates installed costs for specific examples of DER installations.



Operation and Maintenance Costs

The operation and maintenance (O&M) costs of DER technologies have both fixed and variable components. Fixed O&M consists primarily of plant operating labor. It is highly dependent on the operating cycle and staffing philosophy of the plant. Variable O&M represents variable maintenance and is estimated from an algorithm incorporating a DER unit's expected capacity factor. The variable O&M includes periodic inspection, replacement, and repair of system components (i.e., filters, desulfurizer, etc.), as well as consumables (i.e., water, limestone, etc.) computed directly from the DER plant material balance. The table below lists sample maintenance intervals and costs for a variety of DER technologies.

O&M Costs of Selected DER Equipment		
	Time Until Maintenance Required (hours of operation)	**Average Maintenance Costs (¢/kWh)**
Micro turbine	5,000-8,000	0.5-1.6 (estimated)
Combustion Turbine	4,000-8,000	0.4-0.5
Internal Combustion Engine	750-1,000: change oil and oil filter 8,000: rebuild engine head 16,000: rebuild engine block	0.7-1.5 (natural gas) 0.5-1.0 (diesel)
Fuel Cell	Yearly: fuel supply system check Yearly: reformer system check 40,000: replace cell stack	0.5-1.0 (estimated)
Photovoltaic	Biyearly maintenance check	1% of initial investment per year
Wind Turbine	Biyearly maintenance check	1.5-2% of initial investment per year

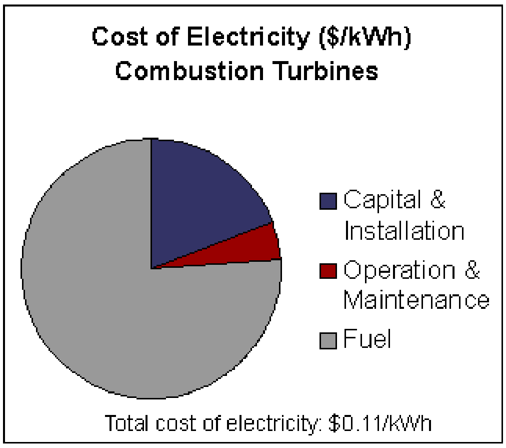
Cost of Electricity

In order to determine the cost-effectiveness of DER technologies, the estimated cost of electricity from a DER system may be compared with the local retail price of electricity from the electric utility or the estimated cost of electricity of another DER technology. For additional accuracy, it is recommended that the cost of electricity be calculated for a specific manufacturer's DER system, as well as for the location and application of the DER system.

The cost of electricity (COE) is comprised of three components: capital and installation (C&I), operation and maintenance (O&M), and fuel (F). The total cost of electricity from a DER device is the sum of these three components, expressed in dollars (or cents) per kilowatt-hour:

Total COE ($/kWh) = C&I + O&M + F

The breakdown of the three components will vary with the size and type of equipment. However, the figure below provides an example of the breakdown for a 4.5 MW natural gas combustion turbine. As illustrated, the fuel component is typically the largest portion of the cost of electricity in a system that utilizes fuel.



The capital cost component varies based on the capital and installation costs, as well as on the fixed charge rate and capacity factor of the DER system. These factors are described in more detail in the Decision Analysis section. The cost of electricity decreases as the amortization period of the DER device increases (e.g., as the fixed charge rate decreases). DER systems with high capacity factors (i.e., base load units) also have a lower cost of electricity.

The operation and maintenance cost component takes into account both the fixed and variable O&M costs of the DER technology. Mature technologies, like internal combustion engines, tend to have lower O&M costs due to standard product designs and established networks for parts and maintenance.

The fuel cost component is simply the cost of the fuel required to generate electricity with the DER device. The fuel cost component varies with the efficiency (or heat rate) of the equipment and with the cost of fuel. Therefore, a specific DER technology may have a lower cost of electricity in some geographic locations than in others due to fluctuations in the cost of natural gas, propane, or diesel. Some DER equipment, such as photovoltaic systems and wind turbines, will not have a fuel cost as no fuel is required.

Decision Analysis

A wide variety of criteria play a part in the economics of distributed energy resources. The following table lists some of the questions that may be asked in the decision-making process for the implementation of DER technologies. The cost of electricity variables in the right-hand column may be defined by answering the questions on the left. The cost of electricity generated in a DER device may then be calculated based on the equations in the previous section. The cost-effectiveness of the DER system can then be determined by comparing the DER cost of electricity to the electricity price from the grid. An example is provided below for calculating the cost of electricity.

DECISION ANALYSIS QUESTIONS	COST OF ELECTRICITY VARIABLES
Application	
Residential, commercial, or industrial? Base load, backup, or peak shaving? Grid independent or grid parallel?	Capacity Factor (CF)
Technology	
PEMFC , SOFC, ICE, CT, PV, and Wind? Average electric load? Ideal power rating of the DER system? Heat rate of the DER system? Reliability of the DER system? Capital cost of the DER system? Installation cost of the DER system? O&M cost of the DER system? Method of payment for the DER system? DER system life?	Fixed Charge Rate (FCR) Total Installed Cost (TIC) Operation & Maintenance Cost (O&M) Average Annual Net Plant Heat Rate (NPHR)
Fuel	
Natural gas, propane, or diesel?	Natural Gas Price (NGP) Diesel Oil Price (DOP) Propane Price (PP)

The cost of electricity calculated based on the above criteria may be affected by additional economic factors, such as:

- Utility stand-by charge
- Net metering
- Incentives or rebates for DER
- Energy efficiency credits for DER

In addition to economic factors, there are a number of intangible issues that may have a role in the DER decision analysis:

- Prestige/status of early adopters

- Global warming concerns
- Emissions concerns
- Green/renewable power advocacy
- Strong feelings for or against utility
- Desire to have independence from the grid
- Safety concerns
- Fuel price instability/volatility
- Special sitting and permitting requirements

One Example

The following example utilizes a simplistic method for determining the cost of electricity. The cost of electricity (COE) is comprised of three components: capital and installation (C&I), operation and maintenance (O&M), and fuel (F).

As an example, a small convenience store may utilize a significant amount of electricity during peak daytime hours. The installation of a DER system is a base load configuration. For this example, the following assumptions are made:

- A natural gas-fueled, 30 kW micro turbine is the chosen DER technology.
- The price of natural gas is $6/MMBtu.
- The micro turbine will operate 19.2 hours per day, 365 days per year.
- The micro turbine has a five-year life.
- The electrical efficiency of the micro turbine (based on the lower heating value of the fuel) is 27%.
- The total installed cost (TIC) of the micro turbine system is $1,000 per kW or $30,000. The interest rate is 0%.
- The total operation and maintenance (O&M) cost of the micro turbine system is 0.5 cents per kW.
- The price of electricity purchased from the utility is 12 cents per kW.
- The waste heat will not be utilized for cogeneration.

Based on the above information, the total cost of electricity generated by the micro turbine can be determined:

- The Self-Generation Incentive Program provides a credit of $1.00 per watt, up to 30% of the project cost. In this case, the maximum credit is $9,000 (30% of $30,000), reducing the total installed cost (TIC) to $700 per kW or $21,000.
- The capacity factor (CF) is equal to the number of hours per year that the DER system operates divided by the total number of hours per year (8,760).

$$CF = \frac{19.2\ \textit{hours per day} \times 365\ \textit{days per year}}{8{,}760\ \textit{hours per year}} = 0.80$$

- The fixed charge rate (FCR) is equal to the annual amortized installed cost ($/yr) divided by the total installed cost ($). In this example, the cost of money was not included. Therefore, the amortized installed cost is simply one-fifth (or one over the amortization period) of the total installed cost.

$$FCR = \frac{\$700\ \textit{per kW} \times 30\ kW \big/ 5\ \textit{years}}{\$700\ \textit{per kW} \times 30\ kW} = 0.20$$

- The heat rate (HR) of the DER system is based on the higher heating value of the fuel. It is assumed that the lower heating value is equal to 0.904 times the higher heating value.

$$HR = \frac{3{,}413\ Btu / kWh \big/ 27\%}{0.904} = 13{,}983\ Btu / kWh$$

- The total cost of electricity (COE) is equal to sum of the components for capital and installation (C&I), operation and maintenance (O&M), and fuel (F).

$$C\ \&\ I\ (\$ / kWh) = \frac{TIC\ per\ kW \times FCR}{CF \times 8{,}760\ hours\ per\ year} = \frac{\$700 \times 0.20}{0.80 \times 8{,}760} = \$0.020$$

$$O\ \&\ M\ (\$ / kWh) = \$0.005$$

$$F\ (\$ / kWh) = \frac{FP}{1{,}000{,}000\ Btu\ per\ MMBtu} \times HR = \frac{\$6.00}{1{,}000{,}000} \times 13{,}983 = \$0.084$$

$$COE\ (\$ / kWh) = C\ \&\ I + O\ \&\ M + F = \$0.020 + \$0.005 + \$0.084 = \$0.109$$

At a price of 10.9 cents per kilowatt-hour, the electricity generated from the micro turbine in this example is less expensive than the 12 cents per kilowatt-hour from the grid. Therefore, in this case, the installation of the micro turbine would be cost-effective for the business owner.

16 members have been answered to the Questionnaire 1. More details are provided in Table 1.

(1) How are "small independent power producer" (SIPP), "combined and/or cogeneration heat and power producer" (CHPP), "renewable and/or alternative energy resources" (RER), etc. defined in the national legislation of your country?

11 members (Albania, Estonia, Kyrgyz Rep., Poland, Latvia, Lithuania, Hungary, Moldova, Romania, Ukraine, Czech Rep.) have indicated on definitions in national legislation and 5 members (Armenia, Bulgaria, Slovak Rep., Georgia, Kazakhstan) have not indicated any definitions.

(2) What are the main features of national legislation on SIPP, CHPP and RER production, pricing, regulation, etc. in your country?

13 members (Lithuania, Estonia, Poland, Bulgaria, Slovak Rep., Czech Rep., Georgia, Romania, Ukraine, Hungary, Kyrgyz Rep., Latvia, Moldova) have indicated different features of national legislation in force and 3 members (Albania, Armenia, Kazakhstan) have indicated on not existing features in force.

(3) What are the shares of SIPP, CHPP and RER in your country's domestic power (heat) production structure (from units constructed up to 1992/ constructed after 1992)?

Responses indicate on 3 countries' groups due to output: Small - up to 8% (Slovak Rep., Georgia, Ukraine, Albania, Kyrgyz Rep., Latvia, Czech Rep.); Medium – up to 30% (Lithuania, Bulgaria); Large – more 30% (Estonia, Armenia, Poland, Romania, Kazakhstan, Hungary, Moldova).

(4) What are the pricing principles and methodologies of price calculations for SIPP, CHPP and RER in your country? Are there differences in pricing for existing and new units of SIPP, CHPP and RER in your country?

8 members have indicated on applications of special principles (Lithuania, Poland, Bulgaria, Ukraine, Hungary, Latvia, Czech Rep., Moldova) and 8 members have not indicated any special principles (Estonia, Armenia, Slovak Rep., Georgia, Romania, Kazakhstan, Albania, Kyrgyz Rep.).

(5) How is trade on SIPP, CHPP and RER production regulated in your country?

11 members have indicated regulations by obligation; contract (quota) (Lithuania, Estonia, Armenia, Bulgaria, Slovak Rep., Romania, Ukraine, Moldova, Albania, Hungary, Latvia) and 5 members have indicated regulation by free market (Poland, Georgia, Kazakhstan, Kyrgyz Republic, Czech Republic.)

(6) What are the tariffs and prices for SIPP, CHPP and RER production, profitability of producers, suppliers?

Law prices – up to 2,5 c/kWh (Kazakhstan, Kyrgyz Rep., Estonia, Armenia); Medium prices – up to 5 c/kWh (Lithuania, Bulgaria, Romania, Latvia, Moldova, Poland-exc.RER, Georgia-exc.CHPP); High prices – above 5 c/kWh (Poland-RER, Georgia-CHPP, Hungary, Czech Rep.)

(7) How does your Government support SIPP, CHPP and RER in the long run term in your country?

12 members have indicated on different governmental support measures (Armenia, Lithuania, Bulgaria, Slovak Rep., Georgia, Romania, Ukraine, Albania, Hungary, Latvia, Czech Rep., Moldova) and 4 members have indicated on non-existing governmental support (Estonia, Poland, Kyrgyz Rep., Kazakhstan-exc. South Kazakhstan hydro).

(8) What are the main regulations on building new CHPP and RER in your country?

8 members have indicated on regulation by permissions, concession, obligations, etc. (Latvia, Lithuania, Bulgaria, Romania, Kazakhstan, Albania, Hungary, Czech Rep.) and 8 members have indicated on absence of any regulation (Estonia, Armenia, Poland, Slovak Rep., Georgia, Ukraine, Kyrgyz Rep., Moldova).

(9) Is there any additional legislation for "green energy" certification?

2 members (Hungary and Latvia) have indicated on application of "green energy" certification.

(10) Please provide any additional information that was not covered in questions 1-9:

Slovakia noted on importance of liberalization for SIPP and RER trade. Kazakhstan noted that regulation includes pricing regulation (regulator's duties) and regulation on policy, strategy, construction, etc. (governmental or ministry's duties).

Armenia have been answered that DG technologies are not applied in the country, mainly due to the significant excess of capacity installed. There are no individual high tariffs for electricity consumed during energy system peak periods. Thus, one of the key factors (decrease the system peak demand) that promote the development of DG technologies is eliminated.

As for generating capacities up to 20 MW, these are small hydro plants in Armenia, their development is stipulated in the Law on Energy in Armenia and is stimulated by the Energy Regulatory Commission. These generating capacities are mostly privately owned, and energy generated there is transmitted to the power grid and is subject to mandatory purchase by the grid. It is quite obvious, that in case of emergency these capacities can be used to provide energy to vitally important consumers. Thereby they will perform one of the important functions typical for DG technologies.

Georgia practically doesn't have Distributed Generations. DG is not defined by the law and therefore is not regulated.

Ten members have been answered to the Questionnaire 2. Summarized results are provided below. More details are provided in Table 2.

Connection To The Grid

<u>1, 2, 3 Existence of Transmission grid code, Distribution grid code, Metering code</u>

Only 4 members (Bulgaria, Czech Republic, Hungary, Romania) have documents that cover all issues of this 3 cods. Estonia, Moldova, Slovak Republic and Ukraine don't have. Latvia has only Transmission grid code, Lithuania - Transmission and Distribution grid codes.

<u>4. What licenses, authorizations and other approvals are needed when a new project is built, an existing project is operated</u>

8 countries apply licenses – Bulgaria, Estonia, Czech Republic, Hungary, Latvia, Moldova, Slovak Republic and Romania. 2 countries – Lithuania and Ukraine don't apply licenses.

Authorizations are needed in 6 countries - Bulgaria, Czech Republic, Latvia, Lithuania , Moldova, and Romania.

Approvals on voltage level are applied in Czech Republic, Hungary, Latvia, Lithuania, Slovak Republic, Romania and Ukraine.

<u>5. How does the project size or voltage interconnection level affect the requirements in previous question</u>

There are different requirements in all countries, depending on the project size.

<u>6. Are there a separate streamlined process and/or standardized interconnection process for small DG? If yes, please describe</u>

Prevailing part of the members don't have separate process. Only in Slovak Republic small DG (under 1 KW) needs an official confirmation on the registration of the generator and its energy equipment

7. Are there any specific environmental standards for the generation equipment?

Only Ukraine has specific standards for DGs.

8. If the local distribution network needs to be upgraded due to a new DG, who is responsible for covering the upgrading cost

Distribution company – in Bulgaria, Estonia, Hungary
Generators – in Czech Republic, Romania
Consumers and DG – in Latvia and Lithuania
Distributor and DG – in Slovak Republic
Individual contract in each individual case – in Ukraine

9. If the local distribution network is strengthen due to a DG, does the project benefit from a discount for connection charge?

No – in all countries except Hungary where DG can benefit upon an individual agreement with distributor.

Definition And Other

1. Is DG defined in the your present legislation or regulatory rules?

No definitions – in Bulgaria, Czech Republic, Estonia, Latvia, Moldova, Ukraine
There are definitions – in Hungary, Lithuania, Slovak Republic, Romania

2. What technologies exist (presently in place) in your country as DG:

Reciprocating combustion engines - Czech Republic, Hungary, Latvia, Lithuania, Moldova, Slovak Republic, Ukraine

Gas turbine engines - Czech Republic, Hungary, Latvia, Lithuania, Moldova, Slovak Republic, Romania, Ukraine

Micro-turbine generators – Latvia, Romania, Ukraine

Hydro units – Bulgaria, Hungary, Czech Republic, Latvia, Lithuania, Slovak Republic, Romania, Ukraine

Fuel cells - Ukraine

Photovoltaics - Czech Republic,

Wind generators –Czech Republic, Estonia, Hungary, Latvia, Lithuania, Slovak Republic, Romania, Ukraine

Landfill gas – Hungary, Latvia, Lithuania, Slovak Republic, and Ukraine

Stirling engines - Romania

Energy Storage systems - Ukraine

Inverters – no one

Cogeneration units – Bulgaria, Czech Republic

<u>3. Who may own the DG equipment?</u>

End-user, Distribution company, Independent third party - Czech Republic, Estonia, Latvia, Moldova, Romania, Ukraine

End-user, Independent third party – Bulgaria, Hungary, Lithuania,

End-user – Moldova

Commercial Arrangements

<u>1. To whom can this electricity be sold:</u>

To a single buyer, to the distributor, to a licensed supplier, to eligible consumers, to any player in the market used by DG host to meet on-site electric loads – Hungary, Slovak Republic, Ukraine

To the distributor, to a licensed supplier, to eligible consumers - Romania

To the distributor and to eligible consumers – Latvia, Czech Republic

To a single buyer and distributor – Bulgaria,

To the distributor – Estonia, Moldova

To a licensed supplier - Lithuania

<u>2. Existence of a regulated distribution tariff, connection charge etc.</u>

Yes – Lithuania, Romania, Ukraine
No – other countries

<u>3. If the DG is intended to meet on-site loads, is back-up or stand-by service required?</u>

Yes – Estonia, Lithuania,
No – Bulgaria, Czech Republic, Latvia, Moldova, Slovak Republic, Romania Ukraine

<u>4. Is the electricity produced by the DG sold at regulated prices?</u>

Yes – Bulgaria, Czech Republic, Hungary, Latvia, Romania, Ukraine
No – Lithuania, Estonia, Moldova, Slovak Republic,

<u>5. Who is responsible for supplying the balancing electricity in the case of a contract between a generator and a market player? Is this balancing electricity sold (in the absence of a balancing market) at a regular price? If yes how much is that price. Do you treat this as a regular consumption or do you use special tariffs. Based on what principles are these special tariffs set?</u>

Balancing market is not established yet – Bulgaria, Moldova
Distribution company – Estonia, Romania, Ukraine
System operator – Hungary
System operator and Market operator – Lithuania
Generator - Slovak Republic, Latvia

6. Are there any provisions to oblige the Regional Electricity Company operating in the area to buy the generated electricity and at what prices?

From combined heat and power generators and renewables – Bulgaria, Czech Republic
From generators under decree of obligatory purchase –Hungary
From small DG - Slovak Republic
From CHPPs - electricity, corresponding to the production of heat delivered to households - Romania

Particular Cases

1. The special case of a self-producer is it treated the same as the case of generators that are not self-producers?

6 countries treat self-producers in the same way as other generators.
In Czech Republic self-producers pay lower prices of system services for self consumed electricity.
In Hungary self-producers usually are less than 50 MW, so they won't need licenses.
In Latvia Distribution companies are obliged to buy surplus electricity for supported cogeneration plants on determined price. From another DG - on agreed price.

2. Are there any incentives to encourage new cogen projects?

There are incentives in Bulgaria, Czech Republic, Hungary, Latvia, Slovak Republic and Romania

3. Are there any incentives to rehabilitate or replace existing old inefficient cogen units?

There are incentives in Czech Republic, Estonia, Hungary, Latvia, Lithuania (theoretically) Romania

4. Are there any incentives for projects of Hydro units?

There are not incentives only in Moldova and Ukraine

5. Are there any incentives for *Renewable (solar, wind)* projects?
There are not incentives only in Bulgaria, Moldova and Romania

Responses on Topic 1

“Pricing policy for small independent generators (micro and small hydroelectric plants, combined-cycle plants and cogeneration plants) and encouraging use of alternative energy resources”
Questionnaire for the Tariff/Pricing committee members

1. How are "small independent power producer" (SIPP), "combined and/or cogeneration heat and power producer" (CHPP), "renewable and/or alternative energy resources" (RER), etc. defined in the national legislation of your country?

2. What are the main features of national legislation on SIPP, CHPP and RER production, pricing, regulation, etc. in your country?

3. What are the shares of SIPP, CHPP and RER in your country's domestic power (heat) production structure (from a units constructed up to 1992/ constructed after 1992)?

What are the pricing principles and methodologies of price calculations for SIPP, CHPP and RER in your country? Are there differences in pricing for existing and new units of SIPP, CHHP and RER in your country?

How is trade on SIPP, CHP and RER production regulated in your country?

6. What are the tariffs or prices for SIPP, CHP and RER production; profitability of producers, suppliers? (Please provide data for the last 5-10 years.)

7. How does your government support SIPP, CHP and RER in the long term (through taxes, prices, subsidies, trading quotas, etc.) in your country?

8. What are the main regulations (law, secondary legislation) on building new CHPP and RER in your country?

9. Is there any additional legislation for “green energy certification” (or possibility for consumers to purchase exceptionally “green energy”)?

10. Please provide any additional information that was not covered in questions 1

State \ Question	1	2	3	4	5	6	7	8	9	10
Lithuania	Yes	Yes	SIPP-0.9% RER-4.8% CHP(e)-17.6%	Yes	Quota- CHP PSO -RER	SIPP:1.6 c/kWh CHP(el)2.73c/kWhCH P(h)1.35-1.63 c/kWh Hydro, bio-5 c/kWh wind-5.5 c/kWh	1) PSO, 2) quotas, 3) prices, 4) funding	Yes (theory)	No	-
Estonia	Yes	Yes	SIPP-4.1% RER-0.4% CHP(e)-95.5%	No(spec.-excl.RER)	Contract	CHP(h)-2.07c/kWh CHP(e)-2.7c/kWh	No	No	No	-
Armenia	No	No /are on preparation	RER-1.4% CHP(h)-45%	No (spec)	Obligation-(RER), Contract-(CHP)	CHP(e): 2.2-2.36 c/kWh+1-3 $/kW per month CHP(h):1.67-1.53 c/kWh. P=1.5%C Hydro-1.2-3 c/kWh P=16%Assets Wind – 5 c/kWh	Obligations on RER up to 2016	-	-	-
Poland	Yes	Yes	SIPP:34-23% CHP(e):52-64% RER:14-13%	CHP:RPI SIPP/RER free contract	Market? RER: 2.4% total CHP(e): obligation	RER: 7.26 c/kWh CHP: 3.24 c/kWh SIPP:2.18 c/kWh	No	Concession	No	-
Bulgaria	No	No (excl.CHP)	CHP+RER: 8-10%	CHP,RER Preferent.	Obligation RER<10 MW; CHP	2.5-3 c/kWh	Obligation on CHP,RER	Open tender >25MW	No	-

Table 1	1	2	3	4	5	6	7	8	9	10
Slovak Republic	No	<5MW(e,t) does not need license	RER - insignificant	No (spec)	Contract	ROI: CHP 6-9 years RER >15 years	Compensate. <70% interest	No	No	Introduc tion of regulat.
Georgia	No	No (excl. CHP)	SIPP: 3.6-2.4% CHP(e): 0.4-0.06 %	No (spec)	Market	SIPP: 3 c/kWh (incl. VAT) CHP(e): 10.8 c/kWh (incl.VAT) P= 10-15%	VAT=0% for production. Distribution 2x VAT	No	No	-
Romania	Yes	Yes	CHP(e):42% CHP(h):36% SIPP:0.03% RER:0.003%	No (spec.)	Compulsory for distribution. company buy pass. CHP(e)	Hydro:1.5-3 c/kWh CHP(e):3-4 c/kWh P=5% reg. Revenue	PPA for 15 years	Yes	No	SIPP/ CHP
Ukraine	<20MW	Yes+	CHP(e):2.9% RER:<1%	Invest-program	Contract	SIPP: P = <10 %	Obligation to buy wind 50% higher tariff	No (project)	-	-
Kazakhstan	No	Nat.monop.	Hydro:10 % CHP(e): 60%	No (spec.)	Market	0.8-1.1 c/kWh confidential !	No (exc. South Kaz. Hydro-quota)	State aid program. for gas turbine PP	No	Min Energy planning
Albania	Yes <2MW	No	Hydro: 1 %	No	Regulated	N/d	Concession	GRTN (Italy) has priority	No	-
Hungary	Yes+	Yes+	CHP(h): 61% RER: 3.6 %	>10%+m >15%+l	Obligation	HVP: 6.8 c/kWh MVP: 7.5 LVP: 7.9 HVOP: 4.3 c/kWh MVOP: 4.7 LVOP: 4.9	Supported interest rates for long term credits	Yes	Yes	-
Kyrgyz Republic	Yes	Yes	RER: 0.15 %	No	No	Small-hydro: 1 c/kWh	No	No(project)	-	-

	1	2	3	4	5	6	7	8	9	10
Latvia	Yes+	Yes+	SIPP+CHP: 0.9% - 6.3 %	Yes+	Regulated	<0.5MW: 0.0433 c <4MW: 0.0361 <0.5MW(RER): 0.05391 c/kWh <4MW(RER): 0.04573 c/kWh CHP(e): 0.031-0.04118 c/kWh	Promotion	Fixed tariff up to 2005	Fix price	-
Czech Republic	RER, CHP	Yes	RER 3 %	CHP, RER min prices	Market	Small-hydro: 4 c/kWh Biomass: 6.75 c Wind, geothermal: 8.1 c/kWh Sun: 16.2 c/kWh	RER: no income tax for 5-y or no real estate tax; Lower 5% VAT	Ministry of Industry and Trade	No	-

SIPP - Small independent power producers
CHPP - Combined heat and power plants
RER - Renewable energy resources

Table 2	Bulgaria	Czech Republic	Estonia	Hungary	*Latvia*
CONNECTION TO THE GRID					
1. Existence of a distribution grid code	Yes	Yes Available on regional distributors Internet pages, for example: http://www.sce.cz/	No	Yes	No
2. Existence of a transmission grid code	Yes	Available in English on http://www.ceps.cz/	No	Yes	Yes
3. Existence of a metering code	Yes	No Metering conditions are part of transmission and distribution codes.	*No*	No Metering rules are contained in transmission and distribution grid codes.	No
4. What licenses, authorizations and other approvals are needed when: **- A new project is built** **- An existing project is operated**	Permits are required for new projects. Licenses are required for operation.	Licenses are required for operation of all generators.	licenses	Licenses - for establishment and operation of a power plant with a capacity of 50 MW or more.	License - to build and operate power plants with capacity above 1MW.
5. How does the project size or voltage interconnection level affect the requirements in Question A. 4?	Permits are not required for generators up to 5 MW. Licenses are not required for generators up to 5 MW.	Authorization process is not required for generators up to 30 MWe.	No different requirements	The establishment of a small power plant shall not be subject to licensing.	Authorization - to build and operate small hydro and wind plant on preferential conditions.
6. Are there a separate streamlined process and/or standardized interconnection process for small DG?	No	No	No	No	No

	Lithuania	Moldova	Slovak Republic	Romania	Ukraine
A. CONNECTION TO THE GRID					
1. Existence of a distribution grid code	Yes	No	No	Yes	No
2. Existence of a transmission grid code	Yes	No	No	Yes	No
Existence of a metering code	No	No	No	Yes	No
What licenses, authorizations and other approvals are needed when: **A new project is built** **An existing project is operated**	Authorization procedure - for installation of new capacities and expansion of the existing generating capacities.	License is needed for power plants with 5 MW or higher. For new projects it is necessary to have the authorization.	- Licenses – to operate an existing project. For generation of electricity or heat from rehabilitated sources under 5 MW, or from other sources under 0.5 MW, no license is required. For a new project with capacity more than 10 MW and heat rate more than 5 MW a preliminary permit is required.	Authorizations for: – achievement of new production; modification of existing energy capacities for production. Permissions for electricity and/or heat production capacities. Operation authorizations for production capacities for electricity and/or heat. License for the production of electricity and/or heat	According to the general legislation on construction.

How does the project size or voltage interconnection level affect the requirements in Question A. 4?	Authorization - to build and operate small hydro and wind plant on preferential conditions.	-	For new project with capacity above mentioned in A.4, a license is required.	The electricity production capacities do not need an authorization if they have an installed power of less than 10 MWe	The size of the demand affects indirectly the voltage interconnection level. The higher is the demand (voltage) the more complicated is technical requirements to connect to the grid.
Are there a separate streamlined process and/or standardized interconnection process for small DG?	No	The process of interconnection for small DG is standard.	Small ones (under 1 KW) need an official confirmation on the registration of the generator and its energy equipment.	*No*	_There is no standardized process. If DG operates in the Wholesale Market, there are standardized conditions (accounting, disclosure, etc.), which DG has to meet.

	Bulgaria	Czech Republic	Estonia	Hungary	Latvia
7. Are there any specific environmental standards for the generation equipment?	**No**	- Act No. 86/2002, on air pollution control (the Clean Air Act) - Act No. 76/2002, on integrated pollution and prevention control - Decree No. 117/1997, on conditions of operating air-polluting sources (including emission limits)	*No*	KTM decree 22/98. (VI. 26.) limits the maximum quantities of SO_2 and NO_x emissions by individual generators with environmental penalty in the case of overdraft. Beginning from 2005. y. generators not able to satisfy emission limits will have to be closed.	There are environmental standards, which limit emission norms.
8. If the local distribution network needs to be upgraded due to a new DG, who is responsible for covering the upgrading cost?	Distribution company	Generators	The local distribution network	The distributor	There are no specific rules only for DG. The existing methodology determines distribution costs between customer and energy company.
If the local distribution network is strengthening due to a DG, does the project benefit from a discount for connection charge?	**No**	**No**	**No**	It can benefit upon an individual agreement with distributor.	Such cases are not predicted in existing connection fee methodology

B. DEFINITION AND OTHER					
Is DG defined in the your present legislation or regulatory rules?	**No**	**No**	**No**	**Yes** - "small power station" - below 50 MW "power station"- above 50 MW.	*No*
What technologies exist (presently in place) in your country as DG	Hydro units Cogen. units	Gas turbine engines Hydro units Photovoltaics Wind generators Cogeneration units Combustion units	Wind generators	Reciprocating combustion engines Gas turbine engines Hydro units Wind generators Landfill gas Power station with: - waste as fuel - biomass as fuel	Reciprocating combustion engines Gas turbine engines Micro-turbine generators Hydro units Wind generators Landfill gas

	Lithuania	Moldova	Slovak Republic	Romania	Ukraine
7. Are there any specific environmental standards for the generation equipment?	The environmental standards are set according the Law on Environment Protection. The Ministry of Environment solves the questions related with the environment protection, construction. It also organizes and also carries out the watch in zones of energetic activities of enhanced pollution.	Environmental standards are established by the Ministry of Environment and territory development and if they are above the standard then penalty is collected.	Emission limits are set for generation equipment. Starting from 2006 they cannot be exceeded. At the same time there are rules and Law on Waste that also contains environmental standards.	Law 137/1995 about environmental protection. Law 293/2002 specifies payable taxes according to the type of emission. GD 472/2000 indicating the measures about water sources protection. GEO 243/2000 regarding atmosphere protection.	Yes, there are specific standards
8.If the local distribution network needs to be upgraded due to a new DG, who is responsible for covering the upgrading cost?	The generators or consumers cover the cost of connection. The connection works are done according to the agreement.	-	DG investor can sign an agreement with the operator of the distribution network on joint funding of the upgrade.	DG is responsible for covering upgrading cost.	Contractual agreement in each individual case
If the local distribution network is strengthening due to a DG, does the project benefit from a discount for connection charge?	There are no any discounts foreseen. The half of connection charge is covered by generator/consumer and the half - by the operator.	-	We do not know about such cases. There is no legal right for a discount for DG, even if the DG is positively affecting the distribution network.	There are no specific provisions indicating discount for DG. This question may be part of an agreement signed with the distributor.	As a rule, nobody gets any discounts. Special legislation and norms have to be developed.

B. DEFINITION AND OTHER					
1.Is DG defined in the your present legislation or regulatory rules?	Yes Small generation is with the capacity up to 5 MW.	No	Yes	Yes	No
What technologies exist (presently in place) in your country as DG	Reciprocating combustion engines; Gas turbine engines; Hydro units; Wind generators; Landfill gas	Reciprocating combustion engines; Gas turbine engines	Reciprocating combustion engines; Gas turbine engines; Hydro units ; Wind generators Landfill gas	Gas turbine engines Micro-turbine generators; Hydro units Wind generators Stirling engines	Reciprocating combustion engines Gas turbine engines; Micro-turbine generators; Hydro units; Fuel cells; Wind generators; Landfill gas; Energy Storage systems
	Bulgaria	**Czech Republic**	**Estonia**	**Hungary**	**Latvia**
3.Who may own the DG equipment?	- End-user -Independent third party	- End-user - Distribution company - Independent third party	- End-user - Distribution company - Independent third party	- End-user - Independent third party	There is no restriction on ownership of generation assets.
C. COMMERCIAL ARRANGEMENTS					
To whom can this electricity be sold	- To the single buyer - To the distribution company	-To the distribution/supply company - To traders and eligible consumers - generators above 10 MW.	Only to the distribution companies operating in the area	- To a single buyer -To the distribution/supply company - To a licensed supplier - To eligible consumers -To any player in the market used by DG host to meet on-site electric loads	- To the distribution/supply company - To eligible consumers
Existence of a regulated	No	No	No	*No* From January 1st 2003.	*No*

distribution tariff, connection charge etc.					
If the DG is intended to meet on-site loads, is back-up or stand-by service required?	There are not such power stations.	*No*	*Yes*	-	*No* There is lack of specific provisions in that regard.
Is the electricity produced by the DG sold at regulated prices?	Yes	*Yes* Only cogeneration and renewables sell electricity at regulated minimal buy-out price (Decision № 1/2002).	*No*	Yes For generators under decree about obligatory purchase of electricity. Some small power stations up to 20 MW have supported price (renewables, CHP, small hydro, landfill gas etc.)	Yes The price of electricity produced by subsidized CHP with capacity up to 4 MW is regulated and depends of type of fuel used.

	Lithuania	Moldova	Slovak Republic	Romania	Ukraine
3.Who may own the **DG** equipment?	- End-user -Independent third party	End-user	- End-user - Distribution company - Independent third party	- End-user - Distribution company - Independent third party	- End-user - Distribution company - Independent third party
C. COMMERCIALARRANGEMENTS					
1.To whom can this electricity be sold	- To a licensed supplier	To the distribution/supply company	- To a single buyer -To the distribution/supply company -To a licensed supplier -To eligible consumers -To any player in the market used by DG host to meet on-site electric loads	- To the distribution/supply company - To a licensed supplier - To eligible consumers	To a single buyer To the distribution/supply company To a licensed supplier To eligible consumers To any player in the market used by DG host to meet on-site electric loads
2.Existence of a regulated distribution tariff, connection charge etc.	Yes Distribution prices are uniform in different distribution companies, as the owner is the same. *	No	**No** The regulator starting with year 2003 will set regulated tariffs for distribution and connection.	**Yes** There are regulated tariffs for distribution and connection change. Regulated distribution tariffs are set for HV, HV/MV, MV, MV/LV, LV.	Yes. Usually, DG does not have their own networks and use networks of regional companies. In case of a trilateral agreement their consumer's pay for using local networks according to regulated regional transmission companies' tariffs.
3.If the DG is intended to meet on-site loads, is back-up or stand-by service required?	Yes	No	No There is no need in back-up services, as energy deliveries from DG are guaranteed	No	No

Is the electricity produced by the DG sold at regulated prices?	No	No, The distribution company is not obliged to buy excess energy generated by small DG, therefore we do not have such methodology.	No Prices for DG energy can be set by contracts	Yes, for hydro on the river, urban cogeneration, regulated fuel supply contracts. There is a methodology indicating the way of splitting costs between electricity and heat. Also, there is a methodology for the negotiation of prices for the purchase of electricity from independent producers and autogenerators. It is compulsory for the distribution companies, to buy the electricity output corresponding to the production of heat delivered to households by CHPPs. Other generators are regulated according to their justified costs.	Yes There is a special pricing methodology for wind generators, small hydro units, and small cogen units approved by Regulator.

	Bulgaria	**Czech Republic**	**Estonia**	**Hungary**	**Latvia**
Who is responsible for supplying the balancing electricity in the case of a contract between a generator and a market player? Is this balancing electricity sold (in the absence of a balancing market) at a regular price? If yes how much is that price. Do you treat this as a regular consumption or do you use special tariffs. Based on what principles are these special tariffs set?	Balancing market is not established yet.	Balancing market exists. Balancing electricity is sold at market price.	For supplying the balancing electricity is responsible distribution company. The balancing electricity is sold at a regular price. The price is the same as for end-users. ?	Hungarian System Operator is responsible. Balancing electricity will be bought by Hungarian System Operator on the market at market price.	Responsible party for supplying the balancing electricity is power company. (in future will be taken over by newly established Transmission System operator). Specific price is not determined yet.
Are there any provisions to oblige the Regional Electricity Company operating in the area to buy the generated electricity and at what prices?	*Yes* Transmission and distribution companies are obliged to by all electricity produced by hydro power stations at regulated price.	*Yes* Only from combined heat and power generators and renewables.	-	*Yes* From generators under decree of obligatory purchase, in the case of refusal of the public wholesaler, which has to buy it on the first place. Prices of obligatory purchase are different, supported and not supported (comparing to average wholesale purchase price). Value of support is returned to the public regional supply company by Hungarian System Operator, which collects it through system operating charges as a component of these charges.	There are no regional electricity companies in market area. ?

	Lithuania	Moldova	Slovak Republic	Romania	Ukraine
5.Who is responsible for supplying the balancing electricity in the case of a contract between a generator and a market player? Is this balancing electricity sold (in the absence of a balancing market) at a regular price? If yes how much is that price. Do you treat this as a regular consumption or do you use special tariffs. Based on what principles are these special tariffs set?	TSO and MO are responsible for the energy balance. According to the regulations the MO calculates the balance energy and balance service prices for Suppliers (Consumers) and Generators. The balance energy price is based on the auction price and non-balance price is equal to the fixed costs of the reserve. It is expected to change a little these regulation, when the hourly electricity trade starts.	Distribution company is responsible to meet all demand.	Depends on who is a market player, and what are contractual terms. The generator is responsible for his contractual obligations. The generator and consumer agree upon the price. The regulator sets the prices for electricity transportation and distribution. If the regulator does not set minimal purchase prices from DG, contractual prices are effective.	The supplier may deliver balancing electricity for eligible customers. If he don't want or cannot do that, distributor is obliged to ensure balancing electricity using regulated tariffs. In case of interrupting electricity deliver by the DG, there are penalties stipulated in the bilateral contract.	As a rule oblenergo (regional organization) is responsible. The problem has not been fully resolved and there is no proper legislative basis.
6.Are there any provisions to oblige the Regional Electricity Company operating in the area to buy the generated electricity and at what prices?	There are 4 types of the public service obligations and they should be bought by the suppliers at these prices:**	We don't have any legislative rules like that. Distribution company is not obliged to buy this energy. If they sign a contract with relevant economic agents (who has small DG) than they would pay in line with the contract. If contract is not signed, but there is	The local distribution network has to buy electricity generated at DG. The relevant distribution company sets the price. In most cases this price is not beneficial for DG. Let's assume that in its decree the regulator will set minimal prices for purchases from DG that will cover reasonable costs.	Yes, it is compulsory for the distribution companies, to buy the electricity output corresponding to the production of heat delivered to households by CHPPs. See paragraphed C4. The rest of generated electricity is sold at negotiate prices.	No The parties work on a contract basis, and if any disputes related to the contract arise they are entitled to address NERC, then NERC acts as a conflict resolver.

		excess electricity in the network, then none would pay anything.			
	Bulgaria	**Czech Republic**	**Estonia**	**Hungary**	**Latvia**
D. PARTICULAR CASES					
Self-producer 1. The special case of a self-producer is it treated the same as the case of generators that are not self-producers?	Yes	No Self-producers pay lower prices of system services for self consumed electricity.	*Yes*	*No* Self-producers usually are less than 50 MW, so they won't need licenses.	*No* Self-producer can offer surplus to distribution company on agreed price. Distribution (public purchaser) companies are obliged to buy surplus electricity for supported cogeneration plants on determined price.
Cogen units 2. Are there any incentives to encourage new cogen projects?	Yes They sell electricity at preferential regulated prices	Yes	No	*Yes*	*Yes*
3. Are there any incentives to rehabilitate or replace existing old inefficient cogen units?	No	Yes	Yes	*Yes*	*Yes*
Hydro units 4. Are there any incentives for such projects?	Yes Preferential prices	Yes	Yes	Yes	*Yes*
Renewable (solar, wind) Are there any incentives for such projects?	No	Yes	Yes	Yes	Yes

	Lithuania	Moldova	Slovak Republic	Romania	Ukraine
D. PARTICULAR CASES					
Self-producer 1. The special case of a self-producer is it treated the same as the case of generators that are not self-producers?	*Yes*	Yes	*Yes*	Yes	*No* Self producers have more problems when connecting to the grid than, for example, DGs of the local electricity distribution company (oblenergo)
Cogen units 2. Are there any incentives to encourage new cogen projects?	*Yes* They are as public service obligations and the suppliers are obliged to buy it according to the set quotas.	No	Yes	*Yes*	*No*
3. Are there any incentives to rehabilitate or replace existing old inefficient cogen units?	*Yes, No* The market (auction) price should encourage the old and costly units replacement. But at the moment there is no real competition. Also main part of the cogen energy is as public service obligations with the state regulated prices.	No	No	*Yes*	*No*
Hydro units 4. Are there any incentives for such projects?	Yes See below listed prices.**	No	Yes	*Yes*	*No*
Renewable (solar, wind)	Yes See below listed	No	Yes	*No*	Yes, there is a special tariff methodology, for tariffs setting that allows covering all costs, related to

Are there any incentives for such projects?	prices.**				electricity generation, as well as costs associated with construction of a plant. They sell electricity to ОРЭ (regional distribution company) at the tariff set by NERC.

* The distribution price at 35-6 kV voltage level is 1,04 Usc/kWh, at 0,4 kV – 1,98 Usc/kWh.
The connection charges are:
1. Capacity fees: 67 US/kW without VAT for one-phase connection and 76 US/kW for three-phase connection;
Distance fees: 14 US/m without VAT for one-phase connection and 15 US/m for three-phase connection.

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No.	Name of PSO	Price, LTLc/kWh
1.	CHP Plants, supplying heat to the networks of district heating of towns	
1.1.	Vilnius CHP Plant	10,05
1.2.	Kaunas CHP Plant	10,93
1.3.	Klaipedos CHP Plant	9,91
1.4.	JSC "Lifosa"	6,4
2.	Lietuvos Power Plant, which generation is necessary for the reserves of energy system	13,52
3.	The costs related to nuclear power system safety improvement measures as well as storage and burial of nuclear waste	60 376 thous LTL
4.	Power Plants, using renewable and waste energy resources	
4.1.	Hydro Power Plants	20
4.2.	Wind Power Plants	22
4.3.	Power Plants, using biofuel	20
4.4.	Operating Power Plants, which supply electricity to 0,4 kV voltage network for 10 years period, when the date is counted since the connection to electricity network	Price fixed in Power Purchase-Sale Agreement on 31/12/2001
4.5.	Other Power Plants, using renewable or waste energy resources	Price is set by separate NCC decision

Note: 1USD = about 4 LTL.